Kangley Echo Lake
Economic Screening and Sensitivity Analysis Report

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Section 1. Executive Summary

Bonneville Power Administration (BPA) proposed the Kangley-Echo Lake transmission line to meet system reliability threats brought about by load growth in the Puget Sound region and treaty obligations to return energy to Canada. These conditions create the possibility of a blackout in the Puget Sound area if certain contingencies, such as a transmission line outage, were to occur during extreme cold weather.

The proposed 500kV line would connect the existing Schultz-Raver 500 kV line with BPA's Echo Lake substation in the Maple Valley area. The proposed route may cross the Cedar River watershed, which provides drinking water for the City of Seattle. BPA funded this study to explore the feasibility of pursuing alternatives to building the Kangley-Echo Lake (KEL) line.

The study team consisted of experts from Energy and Environmental Economics (E3), Awad & Singer, Nexant, Inc., and Tom Foley Consultants. The goals of this evaluation were to:

1. Identify technologies that would be cost effective alternatives to KEL.
2. Evaluate the sensitivity of the cost effectiveness analysis to variations in key input assumptions.
3. Estimate whether achievable load reduction from those cost effective alternatives would be sufficient to defer the line.

1.1 Summary of Approach

We analyzed the cost effectiveness of a broad range of alternatives including Demand-Side Management (DSM), Distributed Generation (DG), large scale Generation (G), and Demand Response and Direct Load Control (DR-DLC). Our analysis estimated the costs and benefits of each alternative from six stakeholder perspectives:

1. BPA TBL Ratepayers (RIM)
2. BPA TBL Revenue Requirement (Utility Cost Test)
3. Total Resource Cost
4. Societal Cost
5. Participants
6. Local Distribution Company (LDC) Ratepayers (RIM)

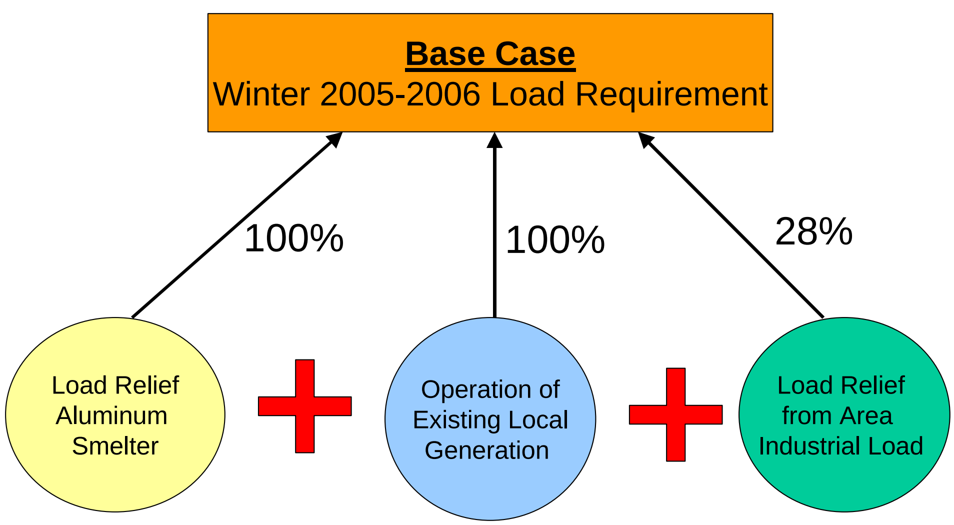
Our analyses of the economics and the required penetration of alternatives were based on BPA system planning information on the transmission system, the proposed KEL line and the conditions requiring additional capacity. In addition, BPA provided general economic assumptions and system characteristics. The team developed the list of alternatives and their cost and performance characteristics from third party sources including the Northwest Power Planning Council DSM database.

1.2 Summary of Findings

A high level of load reduction or additional generation is required to defer KEL. Based on the planning assumptions provided, the level of load reduction required to prevent an overload on the transmission system and to maintain system reliability during a major system outage is approximately 122 megawatts (MW) at the Covington transmission substation during the winter of 2003-2004. This load reduction requirement amount increases every year thereafter. The analysis of the load requirement in **Error! Reference source not found.** provides a thorough description of the load forecasting process.

The Puget Sound Area peak load is approximately 12,000MW. Because of the way that power flows over the network of transmission facilities, each MW of load reduction or additional in-area generation only reduces the flows across the Covington transformer by a fraction of a MW. For example, a 100MW load reduction in downtown Seattle will only reduce loadings on the Covington transformers by 42MW, while the same reduction in Tacoma would only achieve a 20MW reduction at Covington. The ratio of the MW change at Covington to the MW change at the source is called the load flow distribution factor (or distribution factor). When applying these factors, the 122MW that are required to bring the peak load of Covington below overload levels in the first year translates to approximately 381MW of load reduction or additional generation within the Puget Sound Area assuming a distribution factor of 32%[1]. Thereafter, the amount of load reduction or additional generation needed to prevent an overload increases annually. By the winter of 2005-2006 the needed amount grows to 269MW at Covington, or 841MW within the Puget Sound Area. As illustrated in Figure 1, a 3-year deferral of the line would require 100% of the available load relief from the large aluminum smelter in the area, plus operation of all existing generation not expected to be on-line, plus load relief from 28% of industrial load in the area. To put the 28% industrial participation rate in perspective, we reviewed information from 13 utility DR programs, and found only four with participation rates above 5%.

Figure 1: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Base Case Assumptions)



[1] 32% is the load weighted average distribution factor across the Puget Sound study area.

Transmission avoided costs are low. The avoided cost of the KEL project, assuming a cost of $25 million and annual operations and maintenance (O&M) costs of $50,000 for the line, is approximately $1.49 million per year (as calculated using the differential revenue requirement method described in Section **Error! Reference source not found.** of this report). Therefore, in order to prevent increasing TBL's revenue requirement, 122MW of demand reduction at Covington would have to be purchased for $1.49 million or less. This equates to approximately $12.25 per kW at Covington per year or $3.92 per kW-year in the Puget Sound Area based on average load flow distribution factors.

Furthermore, TBL estimates that construction of the KEL line would reduce peak losses on the transmission system by 11MW. This would result in annual energy savings of 48,180MWh, valued at nearly $2 million dollars.[2] Therefore, the economic value of the energy savings is greater than the benefit of deferring the line.

Incentive Levels are low compared to other programs. The likelihood of achieving significant penetration in the area with incentive levels calculated from the avoided cost of deferring the KEL line cannot be determined precisely without a detailed customer assessment. To provide BPA with some general indication, however, we compared incentive levels and penetration rates for 19 demand response programs across the United States with the incentive levels and penetration rates required for cost-effective deferral of the KEL line. From this comparison we conclude that it is unlikely the available incentive payments based on the value of deferring the KEL line would be sufficient to achieve the significant penetration required in this case. Any DR-DLC program designed to meet the load relief needs at Covington would need to achieve higher penetration with a lower incentive level than the programs we observed in our survey.

Demand response is the most cost-effective alternative from a TBL rate perspective. Of the alternatives considered, we found that demand response programs are most likely to be cost-effective from the utility rate perspective and to participants. Demand response is well suited to solving the capacity problem without causing significant revenue loss since it focuses load reduction on only the hours when needed for system reliability. We found, however, that demand response is not cost effective from the TRC perspective because deferral of the line would eliminate the significant loss savings BPA expects the line to achieve. DSM is cost-effective from a TRC perspective, but is not likely to produce win-win outcomes because there would be increased pressure on rates due to increased efficiency, and subsequently reduced utility sales throughout the year or season. We found that DSM programs would need to reduce energy each year from half to one and a half times the annual energy growth. Also, DSM efforts would either have to be funded externally to BPA or the additional costs would have to be passed through to TBL's ratepayers, because the DSM measures do not pass TBL's RIM test.

Scenario analysis indicates alternatives could be cost effective if demand is lower than forecast. To provide BPA with a comprehensive assessment of the potential for cost effective alternatives to the KEL line, we conducted a scenario analysis. The purpose of the analysis was to evaluate the sensitivity of cost effectiveness results to changes in key economic inputs. We tested the entire range of alternative technologies under three sets of economic assumptions. These included the base case which we largely derived from BPA's transmission planning work, an 'optimistic' case that improves the cost-effectiveness and penetration requirements of alternatives, and a 'pessimistic' case that reduces the cost-effectiveness of alternatives. The base case represents our best estimate of the future, and the 'optimistic' and 'pessimistic' cases

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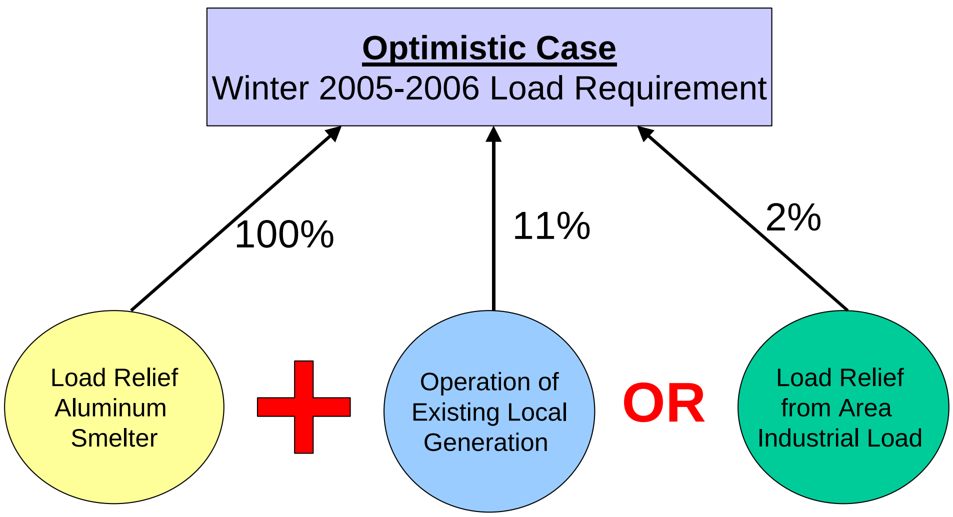
[2] Assumes the 'base case' market price of $40.03 /MWh.

represent extremes that have a low probability of occurring. We found the KEL line was the most cost-effective solution to capacity constraints in both the base and pessimistic cases. In the optimistic case, we found DR and generation were cost effective from both the ratepayer and participant perspectives.

In this optimistic case we estimated that BPA would require 82MW of load reduction at the Covington substation to defer the line for 3 years or 256MW within the Puget Sound Area. As illustrated in Figure 2, this can be achieved through 100% of available load relief from the large aluminum smelter in the area, plus either operation of 11% of existing generation not expected to be on-line or load relief from 2% of industrial load in the area.

Figure 2: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Optimistic Assumptions)



1.3 Summary

The decision whether to build the line or defer the line depends on expectations of demand and the availability of funds for alternatives. Three scenarios were examined to provide insight into this decision. If demand increases at the forecasted rates and funds for alternatives are limited to the value of deferring the line, then the KEL line is the most cost effective and feasible solution. However, if demand were to be significantly lower than expected, then sufficient load reduction potential of alternatives exists to mitigate the need for the line. In this case, the economics of alternatives would also be improved, and it might be possible to defer the line for up to 3 years with demand response programs and contracts with existing generation in the area. Likewise, if additional benefits of alternatives were to be found to offset the costs (for example, through partnering with local distribution utilities), the cost-effectiveness of alternatives could be improved. On the other hand, if demand were to increase at a higher rate than forecasted, then the KEL would again be the most cost-effective and feasible solution.

There are competing views of the appropriate criterion for cost effectiveness. The principal debate is between the Ratepayer Impact Measure (RIM) and the Total Resource Cost test (TRC). RIM compares the effect on TBL's rates of the cost of alternatives versus the capital and maintenance costs of a proposed solution. TRC compares the costs and benefits of alternatives with all the costs and benefits of a proposed solution. TRC includes energy and generation benefits. An alternative deemed cost effective under TRC could cause rates to be higher. While our analysis provides information to evaluate these two criteria, it was not intended to provide guidance as to the appropriateness of one over the other.

Independent of BPA's decision regarding the KEL line, the distribution system benefit of alternatives is an avenue of additional investigation that was not within the scope of this project, but should be pursued. If distribution benefits are significant, they would increase the value of alternative measures and should provide additional sources of funding. The incorporation of distribution benefits involves institutional and policy considerations that are beyond the scope of this analysis and will require more time for resolution than is available for the KEL line decision process.